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A FOCUS DEVELOPMENT FOR HEAVY OIL RESERVOIR: THE LAST FRONTIER AT THE SOUTH BELRIDGE FIELD

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Abstract

The Tulare reservoir of the South Belridge field, CA has been under steam drive since the 1970s. A variety of field development opportunities remain in the southern portion of the field. Over the past two years, Aera Energy has implemented a focus development project to execute the growth strategy for the field. To date, 60 horizontal and 70 vertical producers and 120 steam injectors have been drilled and completed in a 640-acre area. This paper focuses on development strategy, development optimization using reservoir simulation, economic evaluation, and development implementation.

Reservoir modeling has been proved to be a powerful tool for (1) assessing alternative development strategies between horizontal and vertical wells for a multi-sand reservoir, (2) planning optimum pattern configuration and well spacing, and (3) assessing reservoir performance impacts of various operating policy options.

Introduction

Steam flooding

The South Belridge field is located along the oil-rich western side of the San Joaquin basin in Kern County, CA, approximately 45 miles west of Bakersfield (**Fig. 1**). The field ranks among the five largest producing fields in the U.S. The Pleistocene age Tulare formation is the main reservoir and has been produced primarily under steamdrive, or continuous steam injection since the 1970s. The field was developed and operated separately by Shell and Mobil before the creation of Aera Energy by merging their respective California operations in June 1997. The primary area of interest in this paper is the focus development program for the remaining development opportunities in the southern portion of the field. This represents the last frontier of the South Belridge fields.

Field age

Development History. Although the field was discovered in 1911, development of the area did not begin until demand of heavy crude occurred in 1943. Steam soak was started in the 1960s and since the 1970s a number of separate steamflood projects were conducted in different areas of the field. The development involved a variety of staggered line-drive and 9-spot patterns, infill drilling and steamflood expansion programs.

In 1990 a reservroir simulation study[1] was undertaken to determine the optimum steamflood development and operating policy for the undeveloped parts of the field. During 1990-96, the development was continued at a pace of adding about ten new 5-acre, 9-spot patterns per year. However, a number of optimum development issues remained to be resolved: optimum steam utilization allocation between the existing patterns and new development; optimum development pace for maximizing the value of the South Belridge steamflood; and optimum total steam generation capacity. Since the total steam generation capacity was not increased significantly, starting up a new area required that steam injection rates be reduced constantly in existing patterns. It was assumed that steam injection reduction in the old areas would not impact the steamflood performance prematurely.

Development capital expended during 1990-96 was nearly \$60 million to drill and equip over 400 wells in the southern expansion. The development helped in sustaining a production level above 40,000 BOPD in the southern quarter of the field (**Fig. 2**).

(450+1200)/2 = 825

Geologic Setting. The Tulare formation ranges in depth from 450 to 1200 ft, and has been folded into a southwest-plunging anticlinal structure. The dimensions of the reservoir trap are controlled by the overall structure and the stratigraphy of individual sand bodies. The reservoir is composed of alternating layers of unconsolidated sands and impermeable clays that were deposited by a prograding fluvio-deltaic system. There are four main oil bearing zones (B, C, D and E) in the Tulare formation. Within each main zone, the sand may be subdivided into several flow units varying between 10 and

50 ft. Numerous "Christmas-tree"-shaped oil-water contacts appear throughout the structural configuration[1].

A delineation well program was undertaken in 1966-98 to better evaluate the reservoir quality and the boundary of the remaining undeveloped parts of the field. The well locations were selected for possible future use as observation wells or injectors. Based on the information from delineation and existing wells, the net pay map of the Tulare formation shows how the net thickness varies within the reservoir boundary (**Fig. 3**). **Fig. 4** shows the structure based on the top of the lower Tulare.

Rock and Fluid Properties. The sands have an average effective porosity of 35% and a horizontal permeability ranging from 500 md to 5 darcies. Vertical permeability on a gross scale is controlled by the relatively impermeable shale, which acts as local baffles or continuous barriers to vertical flow. Effective vertical permeability appears to be as low as 1% of horizontal permeability within the reservoir sands.

Oil gravity is 13^o API and viscosity is about 1875 cp at the initial reservoir temperature of 95^{o}F. Original oil saturation averages 75% in good quality sands.

API gravity ?

Focus Development Strategy

In 1996 it was determined that the opportunities of developing the remaining reserves in the Tulare be studied to maximize the net present value (NPV) of the field. A scoping analysis was undertaken to evaluate economic sensitivity of various development scenarios. The analysis was based on the existing geologic understanding of the undeveloped parts of the field. It was assumed that reservoir performance and drilling and construction efficiencies would be similar to those from the existing steamflood.

Several development scenarios were evaluated: complete development in 2.5 years, delay development for 1 year, complete development in 5 years, and maintain ongoing development pace. Potential barriers such as steam generation permits, water disposal capacity, manpower requirement, were considered. The economic analysis indicated that the focus development in 2.5 years maximized the NPV of the field. This focus development was also consistent with the company's "grow" strategies for exploration and producing U.S.

Development Process. The Tulare development process uses a multidisciplinary team approach doing conceptual and detailed design of both subsurface and surface systems. The team consists of reservoir engineers, geoscientists, operations engineers, drilling engineers, facilities engineers, and design engineers (contract). Role and responsibilities within the team are largely defined and adjusted by the team. Boundaries between company and contractors are essentially erased. The major task of the team is to design and implement the optimal development strategy in minimum time at minimum capital and operating costs.

Fig. 5 provides the schematic diagram of the development process for the Tulare. The process addresses a number of development and operating decisions under strict time schedules. It uses several channels to advance from the "most likely case" to a final design. The most likely case is the "best guessed" scenario for a "development block" based on avaliable information and existing understanding. Usually, the size of a typical block is about 60 acres, which is a logical unit for development and will fit the drilling and construction scheduling constraints for the block. The delineation or "pilot" wells are drilled and reservoir characterization is refined while pseudomodels are used for performance forecast. Preliminary designs of the surface and subsurface systems are also under way. In the process, it is critical to have flexibility with respect to incorporating new geologic data that becomes available while the optimization studies are in progress. After the development plan is finalized for a block, the construction phase starts and drilling and completion begins. The development process also includes start-up operations such as well hook-up, on production, steam soak, and steam injection. As the development progresses from one block to another, the lessons learned are applied and networked in the future blocks.

Reservoir Model and Performance Forecast

Reservoir model is used to predict reservoir performance under various development strategies. However, reservoir description, which may vary from block to block, is usually not available until the wells are actually drilled. The lead time required to construct the reservoir model based on specific reservoir description and lack of history-matching for model validation makes it impractical to develop various reservoir models for the undeveloped blocks.

A approach similar to the one suggested by Saleri[2,3] is used to maximize the value added from reservoir simulation studies and deliver quick turnarounds between geologic models and decision makings. Lessons learned from previous reservoir simulation studies in existing areas are used to construct a proto-type reservoir model based on reservoir description for a typical development block. Available historical performance of existing patterns and horizontal wells provides "reality check" for the validity of the model. A number of potential modeling problems have been identified and eliminated: spatial distribution of permeability barriers that control the sweep efficiency, effect of fluid migration across pattern boundary[4], and effect of upscaling reservoir properties from geologic to simulation models. Some important aspects of reservoir model development and the use of reservoir simulation for performance forecast and optimization of reservoir development are described next in more detail.

Reservoir Description. A large quanitities of diverse geologic, petrophysical, seismic, and engineering information are managed, processed, and integrated to construct a reservoir model. **Fig. 6** shows the well controls and the areal layout of the simulation model grid for a typical block covering about a 60-acre area. Reservoir properties and reservoir structure are numerically generated by the available 3D visualization/pre-processing software[5]. For efficiency purpose, the geologic model is scaled up for the thermal simulation model. Engineers and geoscientists need to work together to do quality check for the reservoir model. Quite often, modifications of the permeability values in some layers representing continuous barriers to vertical flow are necessary. **Figs 7-8** show distributions of permeability and initial oil saturation of the final model for a typical block.

Model Validation. The most useful way to test the validity of the model is history-match the past performance of the reservoir. Since no performance history is available for the development areas, previous simulation studies in existing patterns are used to provide some insight about the forecast accuracy. A 100-acre area was steamflooded in 1981 and infilled in 1990 (**Fig. 9**). A model representing the typical Tulare reservoir was constructed and hiustory matched from 1981 through 1994. The forecast accuracy of the model was further evaluated by examining the 1994-98 production information. Considering the generic reservoir description and inadequate boundary condition due to fluid migration across the model boundary[4], the reasonable agreement between the simulation and field performance during 1981-97 confirms the validity of the model (**Figs**. **10-11**). Both the history-matched model and the development model use the same commercial thermal simulator[6] and similar model parameters, such as grid size, relative permeability, temperature-dependent oil viscosity, etc. It is believed that the development model is valid as long as the its reservoir description is reasonably appropridate in representing the development area.

Steamflood Performance Correlation. As development continues from one block to another, reservoir quality may change significantly. Yet, it is neither possible nor practical to construct a new reservoir model for every development block to optimize the reservoir performance. During the course of the development study, we tried to determine if there was any correlation on performance prediction among various models. If reservoir performance can be correlated with some reservoir parameter then it may be possible to infer the reservoir performance from the reservoir parameter without actually running simulation. Myhill and Stegmeier[7] suggested that the amount of oil produced by steamflooding might be related to the oil volume to bulk volume ratio (OBVR). This parameter, representing oil concentration of the reservoir, can be calculated as a product of porosity, net/gross ratio, and the oil desaturation on steamflooding. This desaturation is equivalent to the difference between the initial and residual oil saturations. **Fig. 12** illustrates the correlation of performance (in terms of cumulative oil-steam ratio) with OBVR for various reservoir models developed for the Tulare development. For comparison, **Fig. 12** also includes field results reported in the literature[7-8]. Considering the large variation in reservoir properties associated with these field projects and the models, the reasonably tight fit suggests that the steamflood performance correlates well with OBVR. It also suggests that the performance forecasts from various reservoir models used in this study are valid and consistent with the field trend. This correlation has been used to estimate reservoir performance without actually constructing reservoir model for every development block.

Horizontal Well Application. The advance of horizontal drilling technology has made it cost-effective to drill horizontal well that can improve the economic viability of the project. A pilot project was kicked off in early 1996 with the drilling of the first horizontal wells in the undeveloped area adjacent to the expansion patterns. More than 10 horizontal wells were drilled before the end of 1996. A pre-drill simulation study was conducted to answer a number of questions about the horizontal well, such as, how is the performance, where should the well be located within the sand, and what parameters are most important to its optimization. If reservoir description and operating environments are properly accounted for in a reservoir model, it seems to be capable of simulating the horizontal well performance (**Fig. 13**). The application of horizontal well technology has significantly impacted the full field development.

Reservoir simulation model has been used to evaluate the development potential using horizontal wells. Simulation runs were made to address a number of horizontal well design issues. For example, What is the minimum net pay that is worth considering for horizontal well? What is appropriate range of well spacing between injector and producer and between horizontal wells? What if there are physical constraints imposed on the reservoir (e.g., faults, lease boundaries and oil-water contacts, etc.).

A simple, multi-sand generic model was constructed to evaluate steamflood performance relative to sand thickness. Typical steamflood conditions and rock/fluid properties of the development areas are used. As the sands get thinner, the response time to steamflood becomes shorter and oil production reduces (**Fig. 14**). Economic analyses indicate that the minimum sand thickness for a typical horizontal well in the Tulare is about 10-15 ft.

须进 field depth 吗?

Steamflood Operating Policy. Steam is the biggest expense and value driver, accounting for about half of all operating costs. An important question to be addressed when designing the development project is the optimum steam operating policy. The criteria used in determining the appropriate changes in the operating policy are to maximize the long-term net present value of the project. Simulation and economic stdudies indicate it best to inject steam at high flux from start-up until economic limit is reached. Because the fairly flat reservoir is highly stratified with multiple sand and shales, control of steam injection profile using the limited entry technology[9] on a zone (or flow unit, as appropriate) basis is also critical. **Fig. 15** shows the effect of steam flux on the net present value of two typical reservoir models with different reservoir qualities (in terms of net/gross ratio). New development patterns are designed to be steamflooded at about 2 BSPD/net ac-ft.

Focus Development Implementation

Implementation Planning. The planning for development implementation started in early 1996. The development areas were divided into a number of development modules or blocks that formed the logical units for development planning, construction and drilling purposes. Using development experience and analogy of previous southern expansion practices, development was initiated. At this early phase of development, the philosophy around pattern configuration and facilities design is summarized as follows:

- The steamflood is a continuation of the previous southern expansion based on 5-acre, 9-spots using vertical steam injectors.
- The injectots on 5-acre centers are drilled first to provide refined reservoir characterization information for the block.
- The criteria for planning development using horizontal and/or vertical wells is to maximize the net present value of the block, not just the productivity of individual wells.
- Philosophies of facilities desgn include: integrate with existing facilities; defer capital commitments to the extent possible; design for specific project life; provide flexibility through modular, expandable design; and utilize proven, off-the-shelf technology.
- Frequent and open communications among all team members (including contractors) are established early and on a regular basis.

Development by Block. Block 1 covering 60 acres was developed first. Drilling of 12 steam injection wells and 30 vertical production wells (except the existing wells at the boundary) began in January 1997. Decisions on horizontal wells were made after drilling the injectors. The wells were steam soaked and production began in March 1997. In Block 2, 12 injectors and 36 vertical producers were drilled and production started in April 1997.

A 4.2 square mile high resolution 3D seismic survey was acquired over the remaining development region to help delineate and map faulting in the reservoir prior to development. Due to the timing of seismic data acquision and processing, Block 3 development was deferred until the interpretation was completed in Septembet 1997. In the mean time, development continued on Blocks 4 and 5. Block 4, covering a 20-acre area, is located in the northeast flank of field adjacent to an active aquifer. The area was under steamflood (1969-82) followed by water injection, which was later terminated in 1991. In Block 4, some wet sands were present and had to be completed behind pipe.

Delineation and development drilling in Block 5 revealed that it is structurally far more complex than initially anticipated. Since there was no seismic information avaliable, the numerous faults were only loosely determined using delineation wells drilled on 5-acre spacing. Nevertheless, it was decided during the planning that horizontal wells be used as the predominant means of production (as opposed to vertical wells arranged in traditional 5-acre, 9-spot patterns). Considerable difficulties were encountered in keeping the horizontal wellbores in productive sands. It also became apparent that initial well placements were not optimal due to uncertainties associated with fault block geometry. Many planned paths of horizontal wells had to be changed as the fault locations were modified. [Block 5] A total of 10 horizontal producers, 16 vertical producers, and 16 injectors were drilled. In retrospect, however, it appears that development in highly faulted reservoirs without seismic data may be better accomplished using the conventional vertical patterns. The traditional approach tends to overcome high uncertainty with "brute force".

Block 3 is the first Tulare development that has benefited from the 3D seismic survey. The geology is dominated by a series of NW-SE oriented faults bounding a structural high which parallels the main Belridge anticline to the east. A toal of 23 faults were interpreted and mapped with the 3D seismic. Vertical offset of these faults range from approximately 10 ft to greater than 50 ft. However, many of these faults demonstrate lateral variability in vertical offset and may or may not be sealing along the entire length. **Fig. 16** is a 3D seismic cube of Block 3 illustrating the nature of faulting in the southern portion of the structural high. In gneral, the block can be split into three major sections--the eastern, the central, and the western fault blocks. The central fault block is the most structurally complex. **Fig. 17** is a depth structure map on the top of D sand showing these major structural elements.

It is clear from the drilling results and early production that integrating 3D seismic data with 3D geologic modeling has resulted in significant improvement in reservoir understanding and our ability to drill successful horizontal wells within the sands. The development in Block 3 was predominantly horizontal producers with a few vertical producers filling in the gap between the horizontal wells and the competitor acreage. A total of 16 injectors, 12 vertical producers, and 16 horizontal wells were drilled and completed in November 1997.

Block 6 continues the development adjacent to Block 2 and covers 65 acres. The B and most of C zones in the Tulare formation are wet. As a result, the primary pay zones are the D and E. Two faults with a maximum throw of 25-30 ft were identified in the area. Based on a simplistic simulation study, it was decided that Block 6 be developed as all-vertical development. 12 injectors and 42 vertical producers were drilled and completed in March 1998.

Block 7 is the last development block covering 200 acres near the southern edge of the field. From simulation and economic analysis it was assumed that two thirds of the block could be developed with horizontal wells and would be less expensive than the 9-spot vertical program. As many as eight horizontal wells were drilled in the same vertical plane from a compact surface pad. It also appears that production from the horizontal wells can be accelerated by drilling additional injectors closer to the horizontal wells than the primary injectors at 5-acre centers. Block 7 37 primary injectors, 32 infill injectos, 18 vertical producers, and 45 horizontal producers ? were drilled and production started in June 1998.

Development Optimization. Reservoir development involves many decision variables that affect production schedule and project economics. These decision vriables are usually used as input to a reservoir simulator that can predict performance under various development and operating scenarios. The following examples are some of the issues that were addressed during the development planning stage. They are not meant to represent the case studies for development optimization.

Vertical vs. Horizontal Producers. A simulation study based on the east fault block of Block 3 was undertaken to evaluate the development scenarios using vertical and horizontal producers. The results indicate that horizontal wells produce more oil quicker and more efficiently under steamflooding than either 2.5-acre, 5-spot or 5-acre, 9-spot pattern configuration (**Fig. 18**). The improved efficiency seems to be related to less steam breakthrough tendency from horizontal wells. However, the criteria for making the development decisions should be based on economical evaluation. Block 6, having more discontinuous pay sand geometries, is more appropriate for all-vertical development. **Table 1** compares the development costs and economics between vertical and horizontal developments.

Adding New Injectors. In a highly faulted area such as Block 5, the injectors that were drilled first on a normal 5-acre spacing may not be at the optimal locations within the fault block. Simulation is used to estimate the value of new extra injectors. The base case consists of three horizontal wells with two injectors on one side (at 156 ft from the horizontal wells) and two others on the other side (at 78 ft). The effect of adding two new injectors at 233 ft from the horizontal wells is evaluated. Economic analysis shows the beneficial effect of adding new injectors (**Fig. 19**).

Adding Infill injectors. A generic reservoir model based on stratificatic description of Block 7 was developed to evaluate the effect of adding infill (or secondary) injectors over the normal 5-acre spacing with the primary injectors. The base case involves one horizontal producer for each of seven thin sands (10-30 ft) with primary injectors 466 ft apart and 233 ft from the producers. Oil production can be accelerated and improved by adding infill injectors, halfway from the horizontal wells and staggered with the primary injectors (**Fig. 20**). The simulation result indicates that extra steam injection into the infill injectors to increase steam flux from 2 to 2.8 BSPD/ac-ft in the first year is beneficial. Economic evaluation shows that the infill injectors result in incremental net present value as well as improved cash flow during the first 3 years.

Production Performance To Date. Oil production from the development blocks has generally been as predicted. There are the usual operational issues of achieving steam injection rate and vertical distribution targets within the first year and keeping the producers warm (by steam soak) and pumped off. The oil production from the development has reached 15,000 BPD at steam injection rate of 90,000 BPD in late 1998 (**Fig. 21**). The lagging behind the production target is largely from Block 7. The vertical and horizontal wells adjacent to the previously developed patterns are achieving their expected rates, but the horizontal wells farther south are still waiting for thermal connection with the steam injectors. In this case, the infill injectors are providing the heat near the horizontal wellbores much quicker than the primary injectors could achieve. It is expected that Block 7 will be on target within the next 6 months.

Conclusions

1. The focus approach of a multidisciplinary development team to design and implement the large development project under strict time schedules has proven to be critical to ensure optimum development at minimum capital and operating costs.

2. Maintaining a focused organization allows for better instituionalizing of learnings that can be built upon rather than reinvented. Planning, design and implementation improve significantly as the development progresses from one block to another.

3. Various detailed and conceptual reservoir models are used effectively to address technical issues relating to optimization of development design and steamflood operating policy.

4. The criteria for making major investment and operating decisions for field development should be based on economic evaluation of alternative development plans. Since reservoir characterization varies from area to area, development blocks that form the logical units for development planning and implementation become the case studies for development optimization.

Acknowledgement

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Table 1—Comparison of Block 6 Development between Horizontal and Vertical Programs

Development Programs	Horizontal	Vertical
Injectors	7	7
Horizontal Producers	7	0
Vertical Producers	11	42
Recoverable Reserves, MMBO	4.311	5.796
Investment, $MM	3.493	5.053
NPV @ 10%, $MM	3.0	8.2
Rate of Reture, %	30.5	52.3
Profit Investment Ratio, $/$	3.2	4.0
Present Worth Ratio, $/$	2.0	4.0

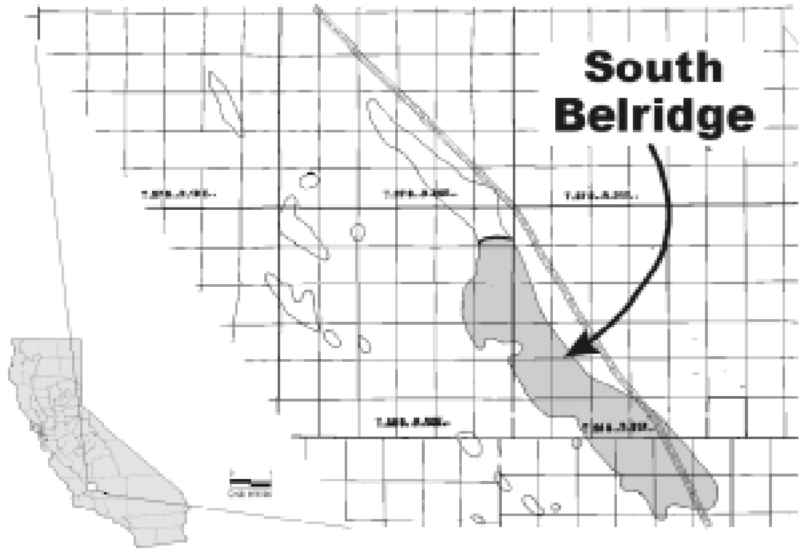

Fig. 1 Location of South Belridge Field

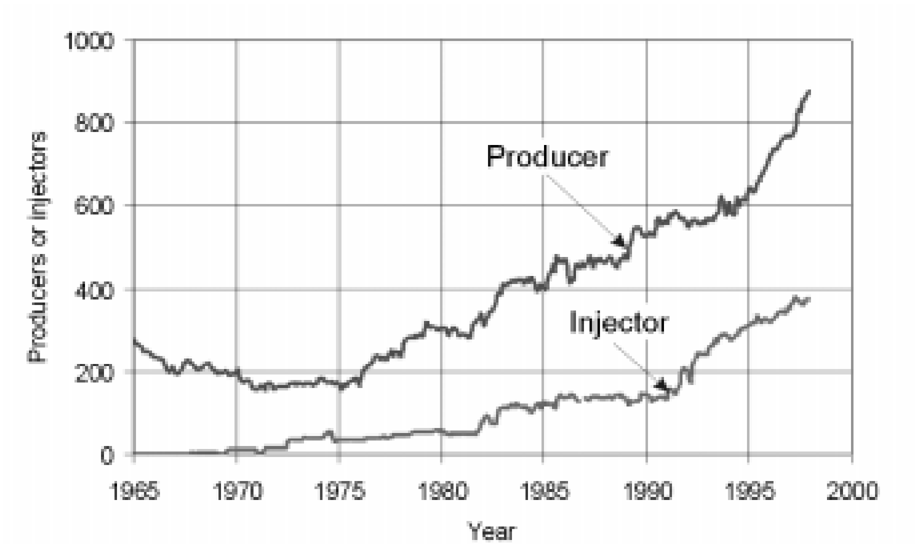

Fig. 2A Number of producers and steam injectors, South Belridge field

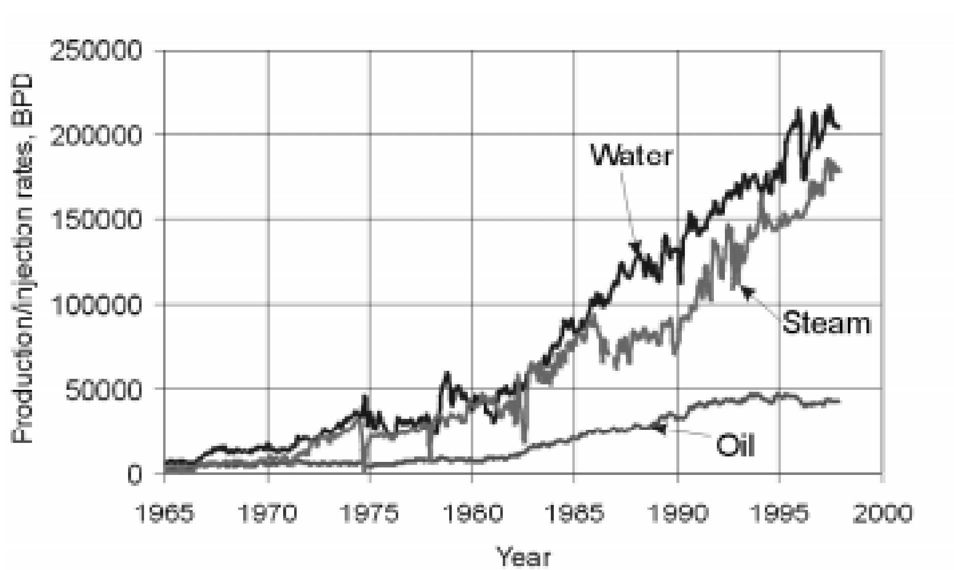

Fig. 2B Production and injection history, South Belridge field

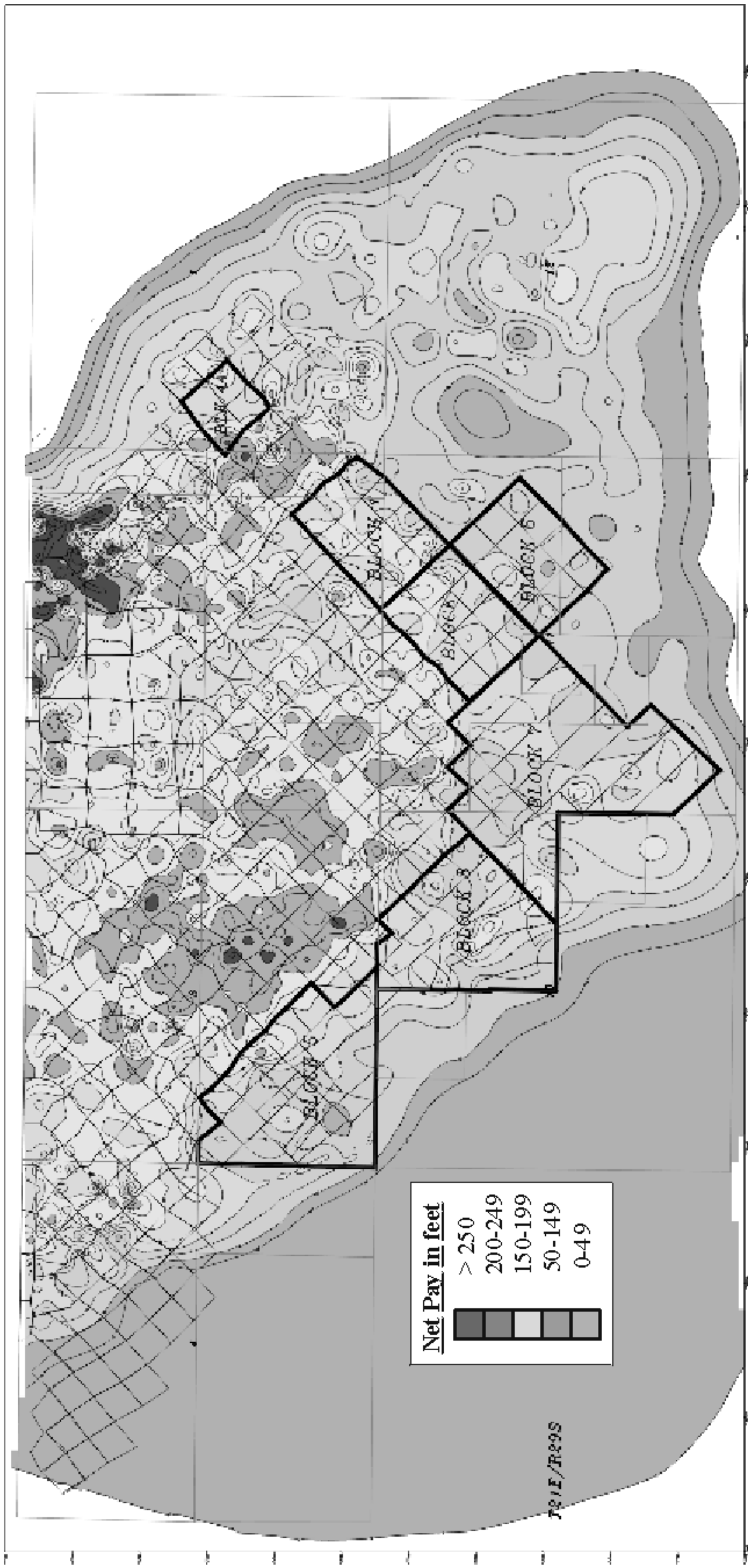

Fig. 3 Tulare Formation Net Pay Map, South Belridge field

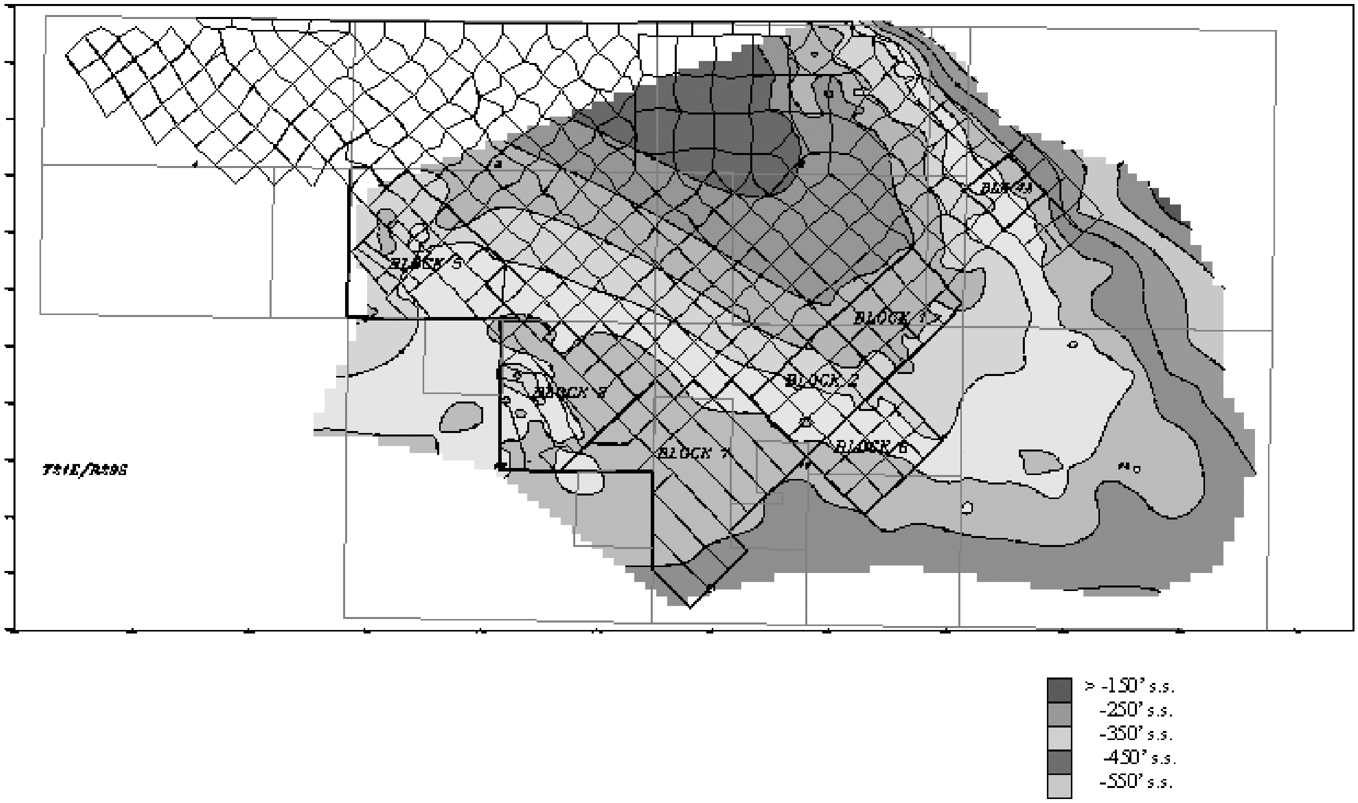

Fig. 4 Tulare D structure map, South Belridge field

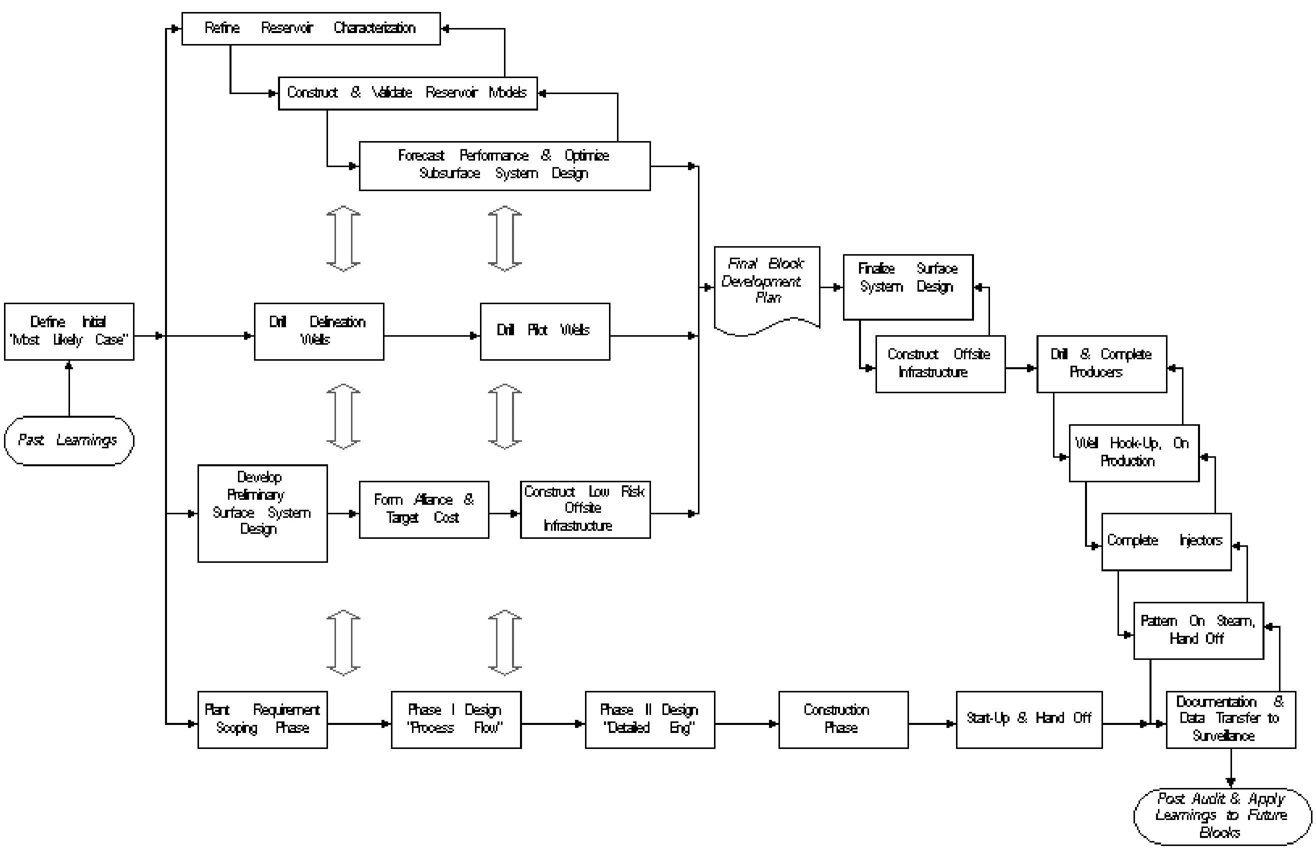

Fig. 5 Tulare development flow process diagram

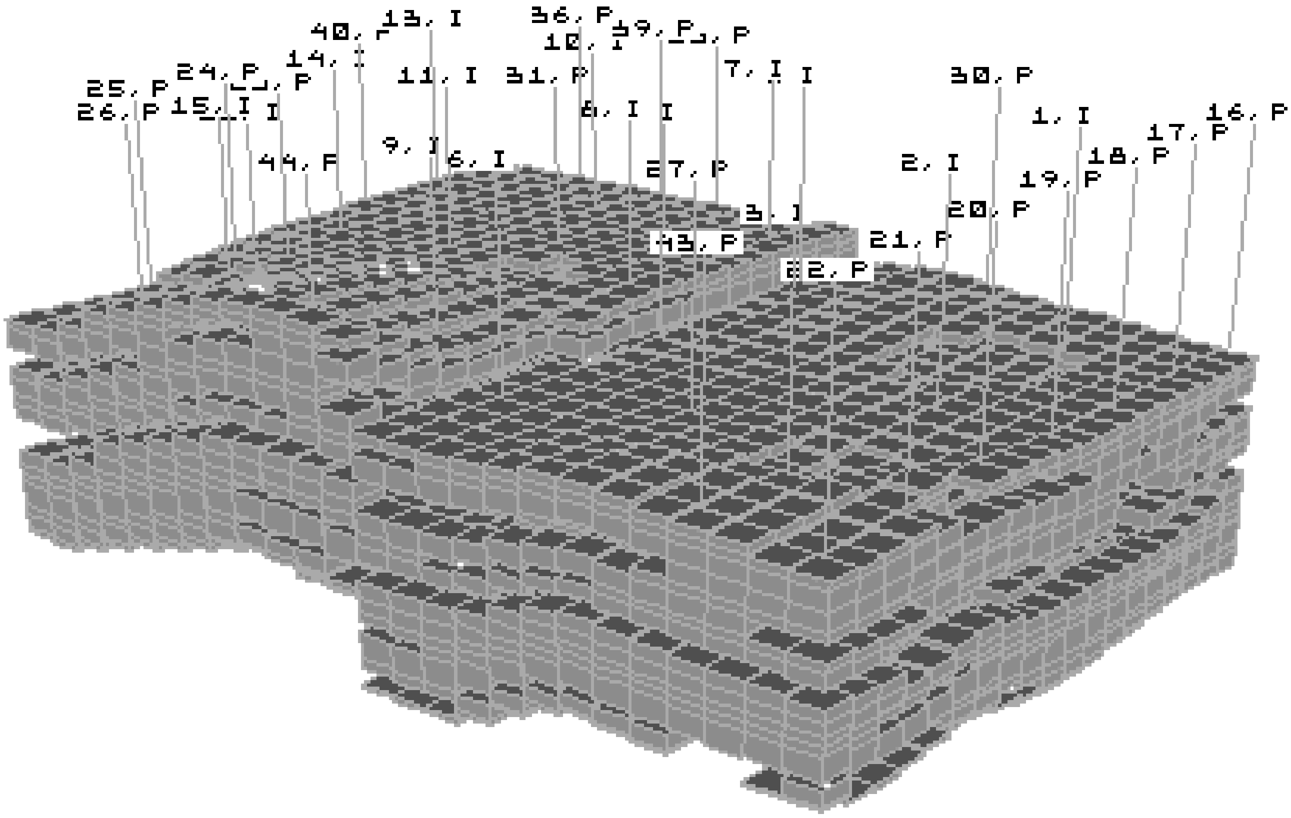

Fig. 6 Grid system for reservoir model, Lower Tulare in Block 3

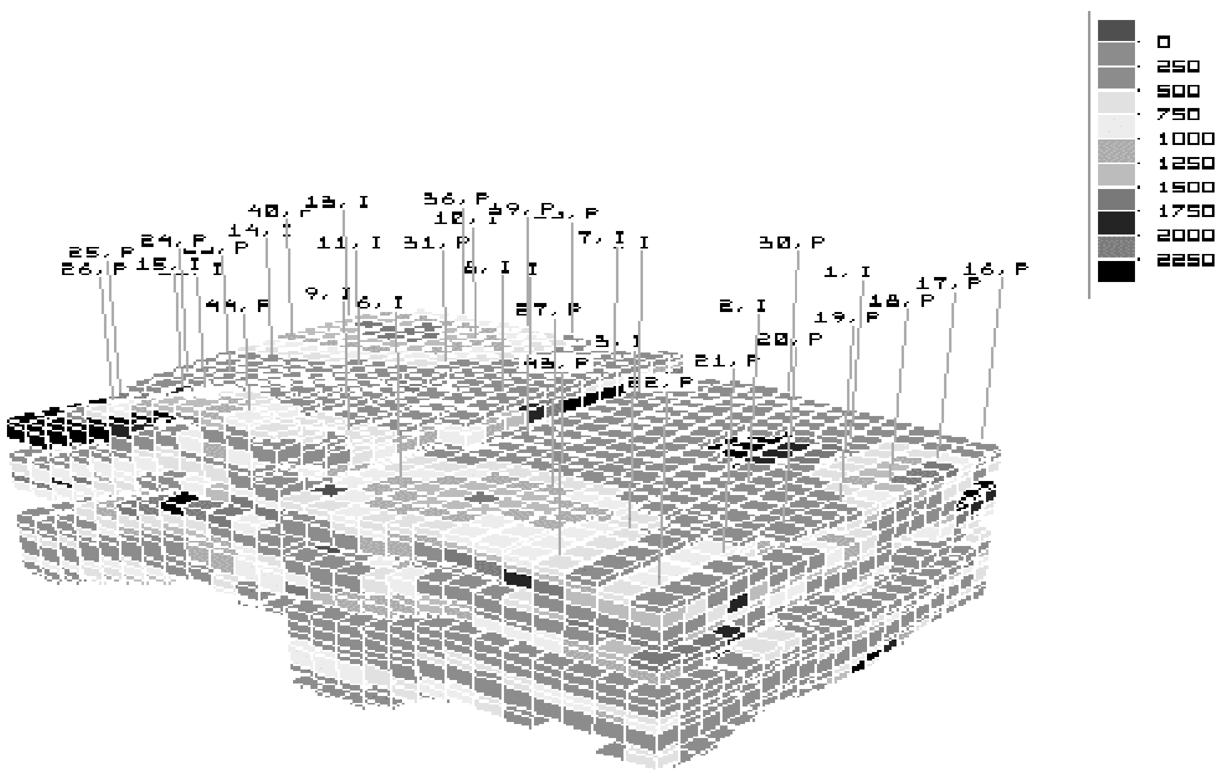

Fig. 7 Reservoir model showing variation of horizontal permeability, Lower Tulare in Block 3

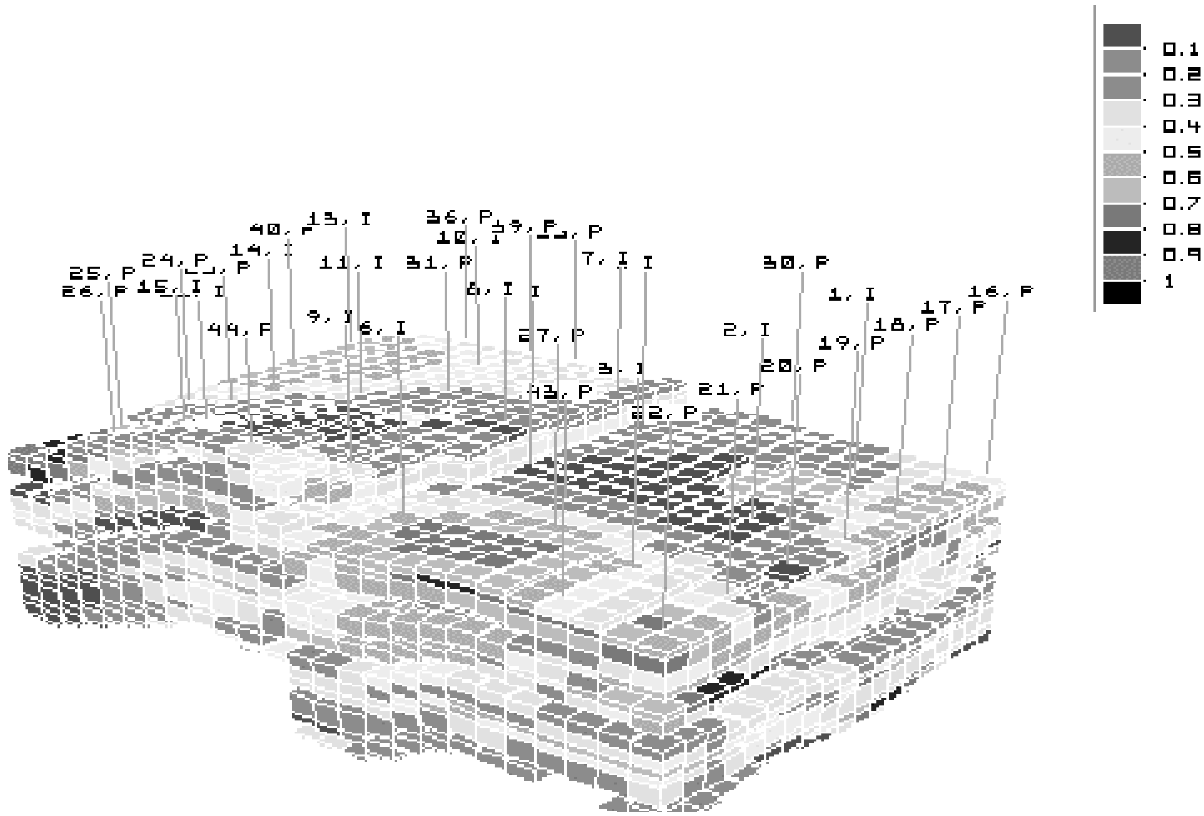

Fig. 8 Reservoir model showing variation of initial oil saturation, Block 3

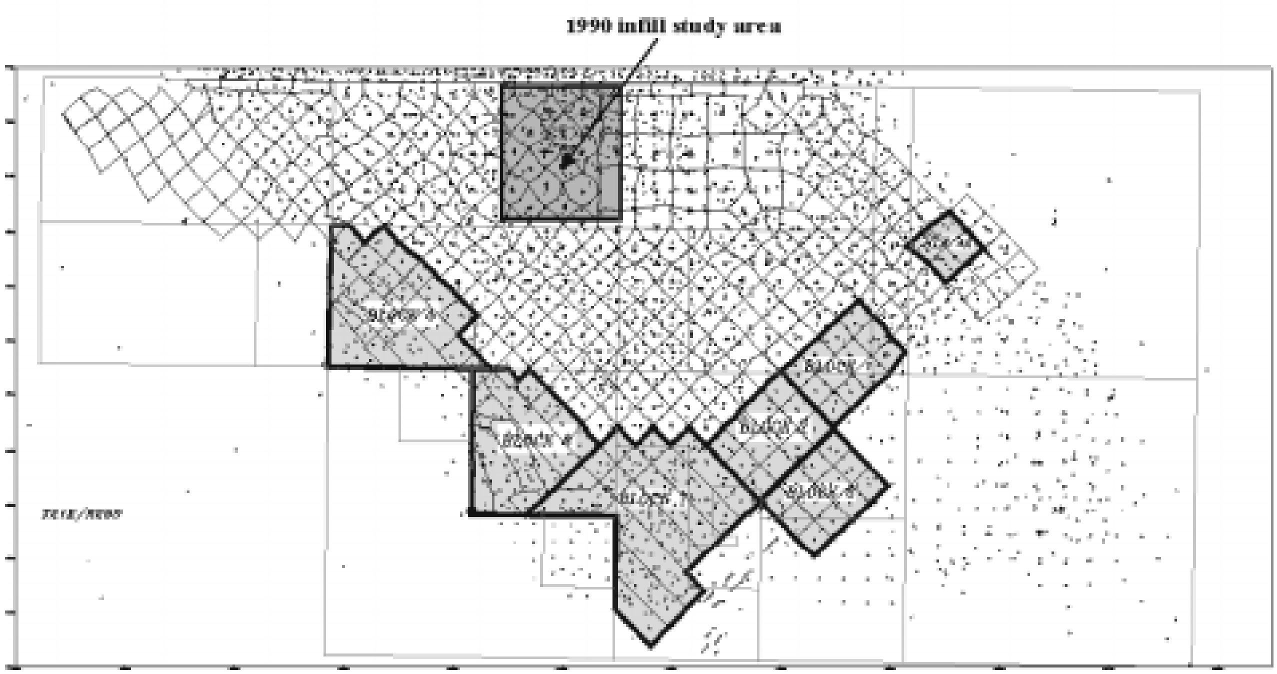

Fig. 9 Model area for 1990 infill study, South Belridge field

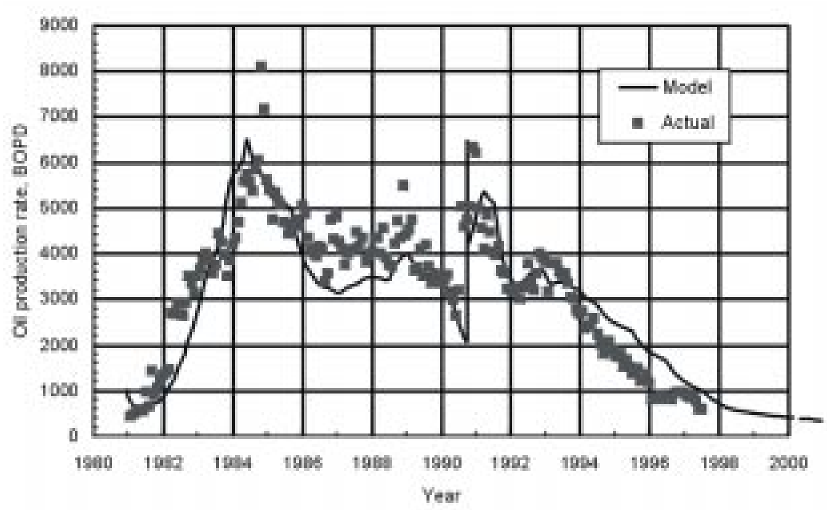

Fig. 10A Oil production rate history match, 1990 infill study

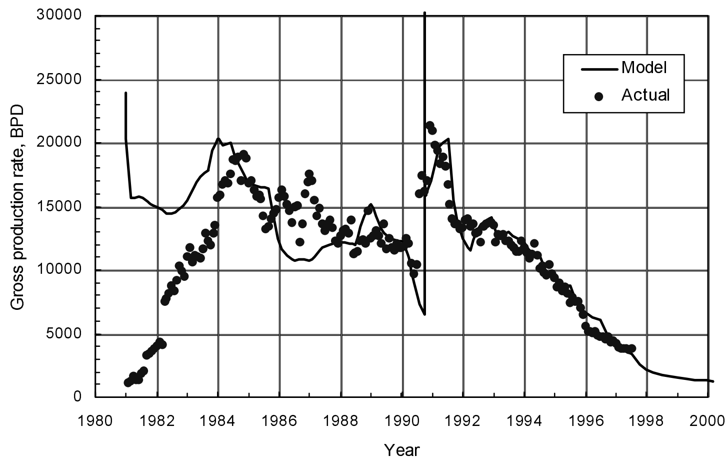

Fig. 10B Gross production rate history match, 1990 infill study

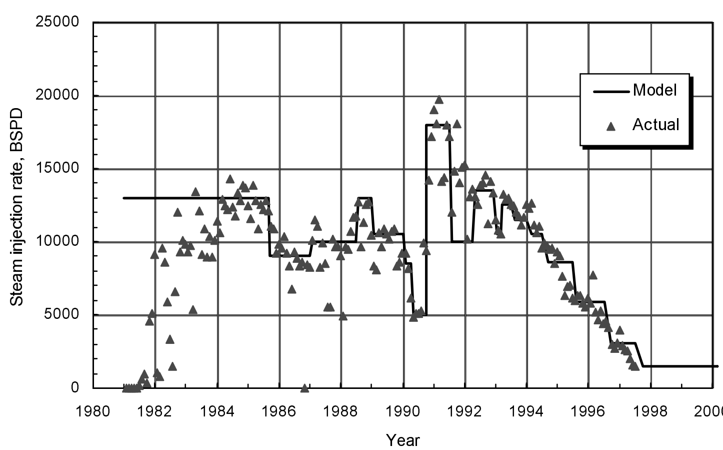

Fig. 11 Steam injection rate comparison, 1990 infill study

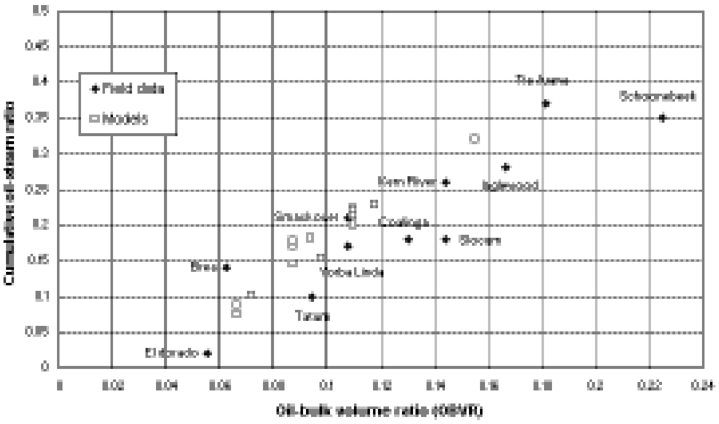

Fig. 12 Steamflood performance correlation with reservoir parameter

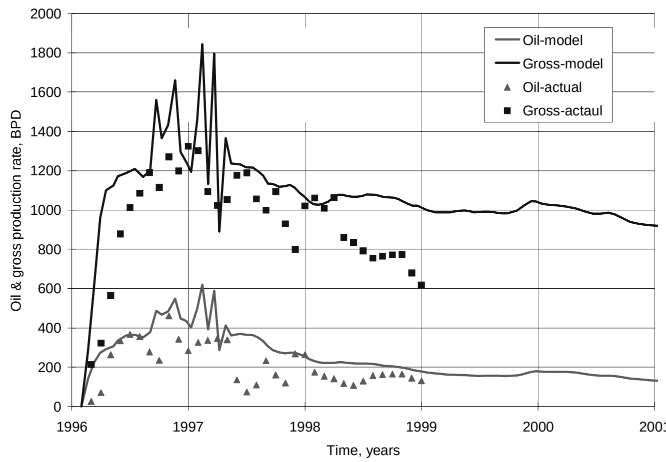

Fig.13 Horizontal well performance, actual vs. model prediction, 3061H-10, South Belridge

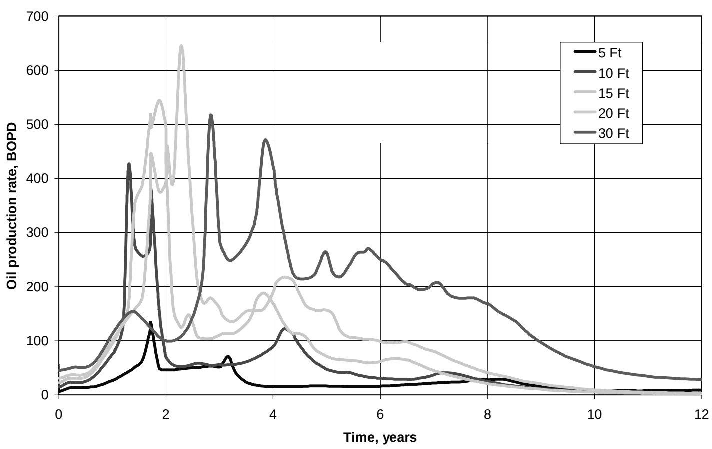

Fig. 14 Effect of net sand thickness on horizontal performance, generic model with net/gross ratio = 0.5

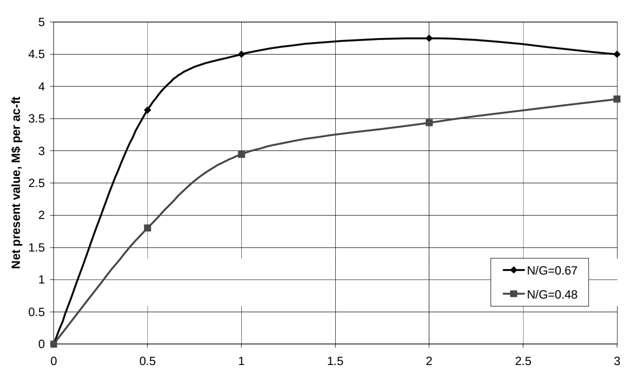

Fig. 15 Effect of steam flux on net present value and its sensitivity to reservoir quality (in terms of net/gross ratio)

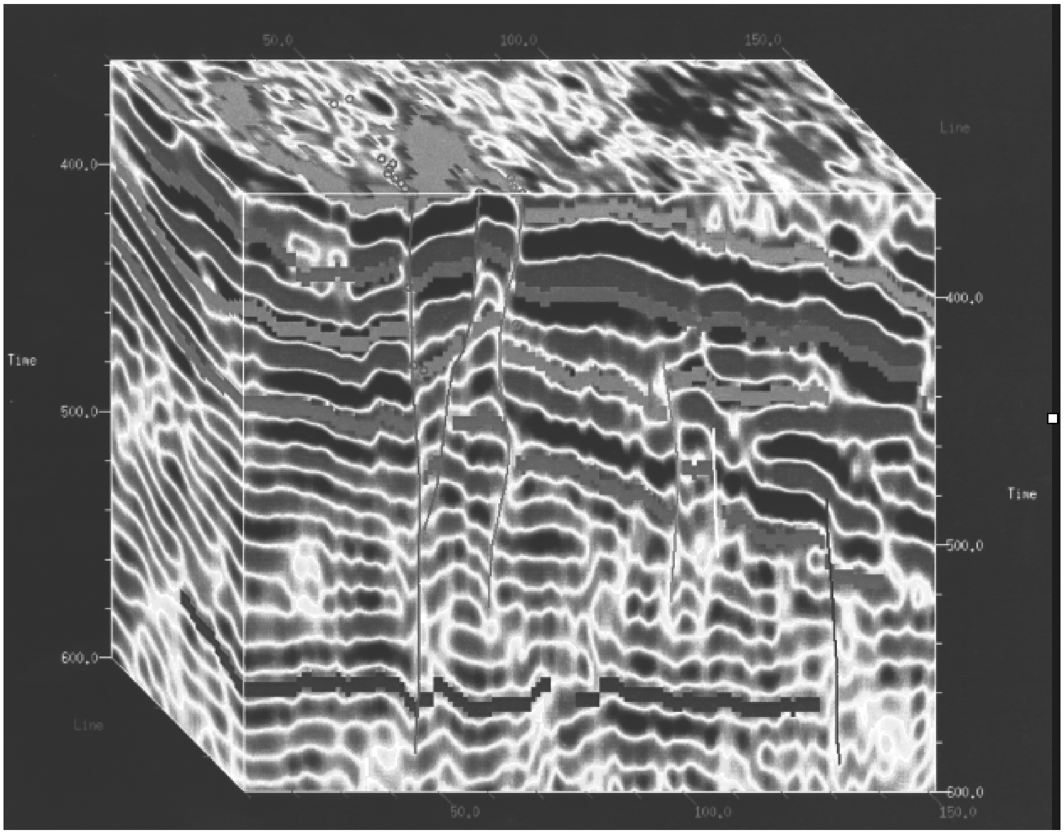

Fig 16 3D Seismic cube of Block 3

Fig 17 Depth structure map showing fault in Block 3

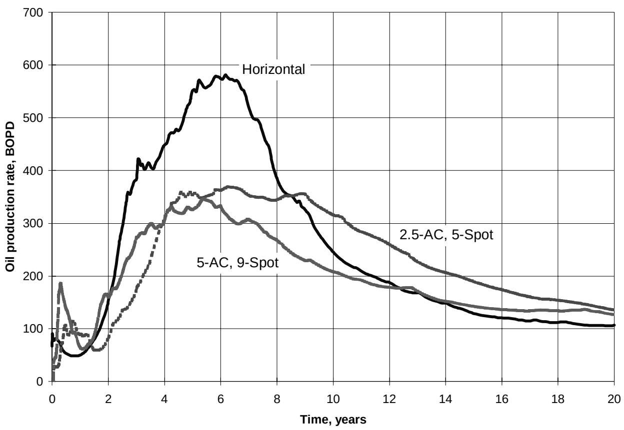

Fig. 18 Effect of development design on production performance, east Block 3

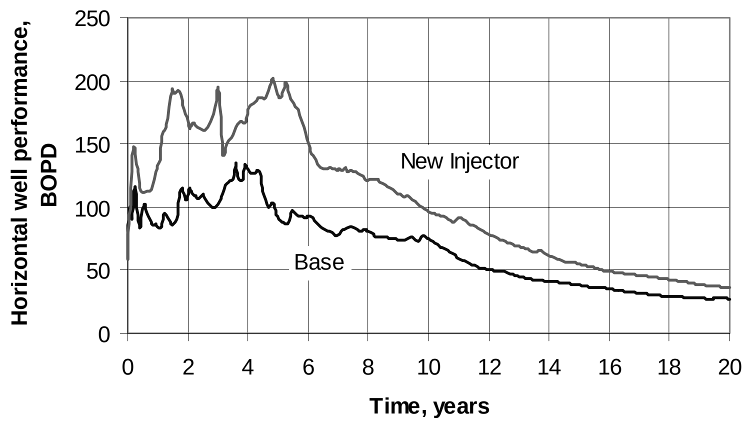

Fig. 19 Effect of new injector on production

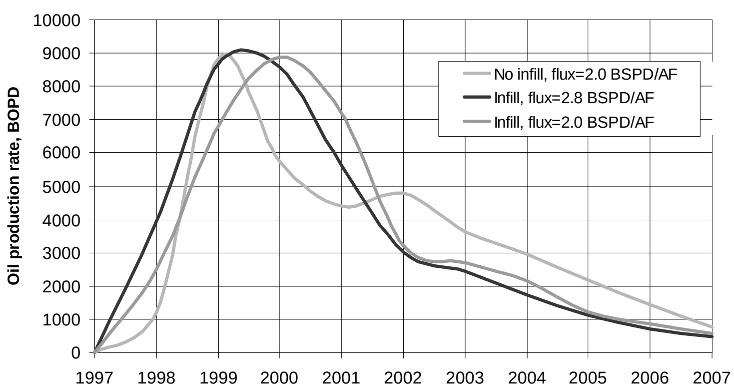

Fig. 20 Effect of Infill Injector on Block 7 production performance

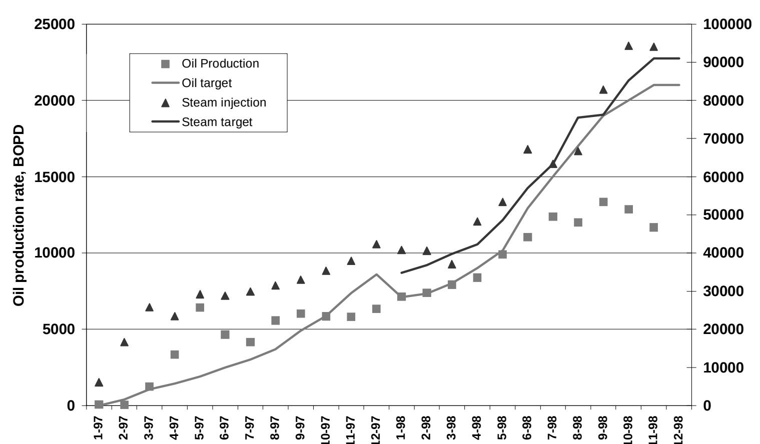

Fig. 21 Performance to date, South Belridge Tulare Development